BP Cherry Point Cogen
DEIS Comment - 18

State of Washington
DEPARTMENT OF FISH AND WILDLIFE

Mailing Address: 600 Capitol Way North · Olympia, WA 98501-1091 · (360) 902-2200, TDD (360) 902-2207
Main Office Location: Natural Resources Building · 1111 Washington Street SE · Olympia, WA

RECEIVED
NOV 03
ENERGY FACILITY SITE EVALUATION COUNCIL

October 31, 2003

Mr. Thomas McKinney
BP Cherry Point Project Comments
BPA Communications Office KC-7
Post Office Box 14428
Portland, Oregon 97293-4428

Mr. Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
Post Office Box 43172
Olympia, Washington 98504-3172

Dear Mr. McKinney and Mr. Fiksdal:

SUBJECT: Comments on BP Cherry Point Cogeneration Project Draft Environmental Impact Statement DOE/EIS-0349

Washington Department of Fish and Wildlife (WDFW) would like to thank you both for the opportunity to review and provide comments on the Draft Environmental Impact Statement for the proposed BP Cherry Point Cogeneration Facility. You will find our comments listed below.

The Applicant is exploring three different options for the facility Transmission System. Two of the options require changes to the current Custer/Intalco Transmission Line No. 2. The Custer/Intalco Transmission Line crosses streams in multiple places. Work conducted in or above waters of the state requires a Hydraulic Project Approval (HPA) from WDFW. We would like to recommend that the Applicant work with the Area Habitat Biologist in that area to discuss the details of the HPA. The Area Habitat Biologist for that area is Julie Klacan and she can be reached at the WDFW Region 4 La Conner office at 360/466-4345 Ext. 272. 1

The Custer/Intalco Transmission Line No. 2 also runs within 330 feet (101 m) of a bald eagle nesting site in Sections 3 and 4 of Township 39 north and Range 1 east. Bald eagles are sensitive to disturbance within 394 feet (120 m) of their nest from the third week in March to mid June while they are nesting and feeding their young. Construction and maintenance of the transmission towers in the area of the nest should be restricted so as not to disturb the bald eagles. 2

On page 3.1-19 under *Erosion Control Procedures*, there is mention of using seed mixes known to effectively stabilize erodible soils in northwestern Washington. We would like to recommend a seed mix for controlling erosion and revegetating the disturbed areas: 3

Mr. McKinney and Mr. Fiksdal
October 31, 2003
Page 2

Calamagrostis canadensis (bluejoint reedgrass) 15%
Festuca pratensis (meadow fescue) 25%
Lolium multiforum (annual ryegrass) 25%
Poa palustis (fowl bluegrass) 25%
Trifolium repens (white clover) 10%

3 cont.

Thank you for the opportunity to provide comments. We hope that you find them helpful. If you have any questions, my phone number is 360/902-2615 and my email is kloemkak@dfw.wa.gov.

Sincerely,

Karen Kloempk

Karen Kloempken
Fish and Wildlife Biologist

KK:kk

cc: Curt Leigh
David Mudd

BP Cherry Point Cogen
DEIS Comment - 19

NW Energy Coalition NW EC
For a clean and affordable energy future

Washington
219 First Avenue South, Suite 100
Seattle, WA 98104
206.621.0094 • 206.621.0097 (fax)
Oregon
4422 Oregon Trail Ct. NE
Salem, OR 97305
503.851.4054 • 503.390.6287 (fax)
nwec@nwenergy.org
www.nwenergy.org

Allen Fiksdal
EFSEC Manager
P.O. Box 43172
Olympia, WA 98504

October 30, 2003

Dear Mr. Fiksdal,

Please find enclosed my comments on the BP Cherry Point Cogeneration DEIS.
I have also sent them to you electronically.

Thank you,

Trina Blake
NW Energy Coalition

RECEIVED
NOV 03 ...
ENERGY FACILITY SITE
EVALUATION COUNCIL

RECEIVED
NOV 03 2003
ENERGY FACILITY SITE
EVALUATION COUNCIL

TO: Members, WA State Energy Facility Site Evaluation Council

FROM: Trina Blake, NW Energy Coalition
DATE: October 30, 2003
RE: BP Cherry Point Cogeneration Project DEIS

Thank you for the opportunity to comment on the BP Cherry Point Cogeneration Project DEIS, specifically on the proposed CO2 mitigation proposal.

We appreciate the Council addressing the issue of Greenhouse Gas emissions, and including a section on its cumulative impacts. However, while the DEIS says there is "still uncertainty" about the magnitude of future impacts of global warming (section 3.2.5), EFSEC members are already clearly on record acknowledging that the risks of waiting to act on global warming are too great. The first impacts are already being felt, from reduction in the snowpack to forest infestations, and even the low-end of predicted changes will have dire consequences. The Council has heard from scientists such as Dr. Richard Gammon and the University of Washington on the impacts to Washington State from global warming. Scientists quoted in the DEIS itself predict that global warming will impact the Pacific Northwest in the next 50 years by reducing snow pack, increasing precipitation in winter and decreasing precipitation in summer, all of these leading to adverse impacts on irrigated agriculture, forests, and salmon. The region's traditional base load power source, hydroelectric dams, are also threatened by summer flows 20-30% beneath current levels, with significant impacts on summer power production and rates. These impacts to Washington, if CO2 is not reduced will be devastating to the economy and the environment. Obviously, any new plant permitted would increase emissions.

The DEIS does contain some very good proposals. First, decommissioning of the old boilers is a great idea and should be made an absolute requirement of building the proposed facility. The boilers are polluting and unnecessary, and should be permanently removed. 1
Second, fully mitigating CO2 emissions from the proposed plant through BP's corporate greenhouse gas objective is an excellent plan. However, we understand TransCanada already plans to purchase the facility permit. Because BP is committed to reducing CO2 around the globe, the company should make full mitigation a condition of sale, perhaps even working with TransCanada to mitigate CO2 emissions. Assuming that this is not made a condition of sale, we now must address the alternative proposal, which is wholly inadequate, as it is not based on sound scientific or economic principles. 2

Plan if the Plant is sold:

Capacity Factor

This plan has a capacity factor assumed to be 85%. This might be acceptable if the plant's CO2 emissions were mitigated fully, but to allow a reduced capacity without full mitigation invites gaming. Oregon requires, and this plan should too, a capacity factor to be assumed at 100%. 3

Emissions Limit

In calculating the emissions to be mitigated, the current Oregon standard (suggested in the DEIS), which requires emissions exceeding 0.675 lb/kwh (River Road technology minus 17%) to be mitigated, no longer reflects the most efficient combined cycle combustion turbine technology available. The Council should require mitigation of emissions from the 4

baseline of the most efficient combined cycle combustion turbine operating at the time the
final mitigation plan is approved. Based on our research, the most efficient combustion
turbine technology currently available is the Siemens Westinghouse W501G turbine at 0.764
lbs CO_2/kWh. Applying the 17% reduction in the Oregon standard to this technology would
yield a baseline of 0.634 lbs CO_2/kWh. But we are not recommending 17%. We would like
to see full mitigation as proposed under BP ownership. We have also recommended to the 4 cont.
Council a very economical standard of 0.458 lb CO_2/kWh, based on 40 percent below
emissions from a state-of-the-art combined cycle gas-fired plant (See attachment A, the
Tellus economic study on CO_2 mitigation). Governor Locke has called for a minimum of
20% of total emissions to be mitigated.

<u>Payment</u>

The suggested price, $0.85/ton, reflects the outdated and insufficient Oregon standard,
in practice leaving 95% of CO_2 emissions unmitigated. The time frame for payments (annual
over 30 years) would effectively gut any ability of this proposal to mitigate CO_2. In order to
actually mitigate a ton of CO_2 emissions, the funding must be at a level near the market cost
of mitigating that ton (between $2 and $5/ton based on Seattle City Light and Climate Trust
figures). This could be achieved by setting the mitigation price at the current market price (2-5
dollars/ton CO_2) and indexing the price to the CO_2 offset market for any payments that occur
in the future. The DEIS proposal also endorses annual payments spread over 30 years.
Annual payments would unnecessarily constrain the types of CO_2 mitigation projects that
could be purchased, and thereby increase costs. The project owner should plan on providing
the total amount of payment within the first five years of facility operation. That is a 5
modification on the Oregon standard, which requires a single up front payment at the
beginning of facility operation. Providing the mitigation payment up front allows the entity
acquiring the offsets to purchase larger, more cost-effective mitigation projects. It also
reduces any uncertainties associated with adjusting the price per ton to a market index over
time. If however, EFSEC approves an annualized requirement, that requirement must apply
for the entire life of the project and be indexed to market prices. In addition, the 30-year
facility life proposed is based on Oregon law. Oregon uses a shortened estimated life span as
an incentive to follow their monetary path and pay up front. If full upfront payment is not
required; the mitigation should be required for the actual life of the proposed facility.

This proposal also omits administrative costs. If the proposal includes a monetary
compliance path, it must explicitly include additional administrative costs of the entity
managing the offset projects. As EFSEC found in its order on the Sumas Energy 2 facility, it
had the legal power to impose administrative costs, and believes, in general, that it is
appropriate to require the certificate holder to help pay such costs. Administrative costs are
an essential part of ensuring that mitigation is accomplished in a credible manner that will 6
count toward future regulatory requirements. The Council should recognize the true cost of
the administration. In the Satsop agreement approved by Council members, administrative
fees were set at 7.5%. Undercutting the real cost would further reduce the effectiveness of the
mitigation, as money from the cost per ton would have to be used in order to secure projects

Finally, the plan must require the applicant to choose (if both are offered) between a
monetary path (money paid to a third party) and mitigation obtained by the owner of the
facility. To allow both invites gaming and further undercuts real mitigation. Any mitigation
obtained directly by the owner of the proposed facility should be acquired at cost. To allow 7
direct mitigation at the same price as the monetary path further reduces the tons of CO_2
mitigated

The extraordinary threats to Washington's environment and economy associated with greenhouse gas emissions are well documented. EFSEC's final EIS decision should strike an appropriate balance between the costs and benefits of these facilities. A strong mitigation requirement now will significantly reduce environmental costs AND financial costs. Utility and financial analysts universally project that the value of CO2 offsets and allowances will increase as binding constraints on greenhouse gases are adopted worldwide. Relatively inexpensive mitigation now is low-cost insurance against compliance costs that will rise as the right to emit CO2 becomes an increasingly scarce and valuable commodity. We urge the Council to ensure that the CO2 mitigation plan achieves a meaningful environmental goal and substantially reduces exposure to future costs associated with purchasing CO2 allowances or credits. Again, thank you for this opportunity to comment, and for your commitment to reduce the environmental and economic costs associated with CO2 emissions from this proposed facility. 8

Attachment "A"

An Economic and Financial Analysis of the Proposed CO2 Rule
Comments for the Energy Facility Siting Council[1]

Michael Lazarus, Senior Scientist, Tellus Institute[2]
July 31, 2003

Introduction
I appreciate the opportunity to comment on EFSEC's proposed CO2 rule. I am a Senior Scientist with Tellus Institute, where I've done energy and environmental analysis for nearly 20 years, climate policy studies for the past 12 years, and analysis of emissions trading and offsets for the past 6 years. I work with a wide variety of clients, funders, and collaborators, including from the World Bank, USEPA, state and local agencies, foundations, project developers and brokers, and the non-governmental organizations. Among other current duties, I presently sit on Methodology Panel of the Clean Development Mechanism of the Kyoto Protocol, which is charged with developing draft guidelines and procedural recommendations for what could be considered the world's largest offset market.

Basic Approach
In this instance, I've been asked by the Northwest Energy Coalition to examine the economic and financial impacts of various possible formulations of a CO2 standard. This summary provides an overview of key assumptions and results. The analytical methodology, which combines straight-forward cash flow analysis, busbar electricity cost calculations, and cost-benefit comparisons, is detailed in an accompanying spreadsheet.

I have used widely available data and assumptions – drawn largely from Northwest Power Planning Council (NPPC) documents, supplemented by published studies by the US Department of Energy (USDOE), the Massachusetts Institute of Technology (MIT), and personal experience and contacts in the offsets market -- to calculate cost impacts across a range of proposed offset requirements (17%, 40%, and 100% of plant emissions) and mitigation prices, from the Oregon standard price[3] to the "all-in" cost of acquiring offsets (market price plus administrative and production costs).[4] For simplicity, I only consider one payment option – upfront payment spread over 5 years, financed by the developer – for a hypothetical 540 MW natural gas fired combined-cycle plant, placed in service in 2005.[5] I then look at the overall impact on the costs of

---

[1] Draft results were presented at EFSEC's July 17 public meeting in Olympia. Updated results are presented here reflect further refinements of the analysis.
[2] Contact information: 119 First Ave S, Suite 400, Seattle, WA 98104, (206) 985-8124, mlaz@tellus.org.
[3] The Oregon CO2 standard price has been at \$0.85/tCO2 for a several years, after increasing 50% from its original \$0.57/tCO2 level. The price is allowed to increase by up to 50% every 2 years to more closely match prices actual paid for offsets. I assume that by 2005, the OR price will be at 0.85 x 1.5 or \$1.28/tCO2, given that offset prices are already well above this level, and that the price rises at 10%/year afterwards, roughly matching historical trends. (All "t" represent short, rather than metric, tons except where indicated)
[4] I have used rather conservative estimates of the market costs of offsets: \$2.50/tCO2 in 2003 rising to \$5/tCO2 by 2010, plus \$0.5/tCO2 for production/administrative services (contracting, M&V, baselines, etc.) that are essential for providing quality offsets. See World Bank's State and Trends in the Carbon Market reports at www.prototypecarbonfund.org
[5] Key assumptions were derived from the "Default assumptions from: NW Power Planning Council, New Resource Characterization for the Fifth Power Plan, Natural Gas Combined-cycle Gas Turbine Power Plants", August 27,

producing electricity from this power plant, and how a change in overall costs would be reflected in consumer rates, assuming such changes were passed through in rates rather than absorbed by developers as lower (or higher) profits. This assumption may overestimate rate impacts considerably.

Avoiding future compliance costs

It is important to recognize that investing in emissions reductions now hedges not only against future climate impacts, but also against the financial liabilities of major new assets responsible for significant emissions. These prospective liabilities are increasing in prominence and magnitude, as reflected in greater corporate and shareholder concern for greenhouse gas (GHG)-intensive activities, and in rising regional and national legislative activity.[6] While the timing and stringency of mandatory controls economy-wide or electric-sector-wide CO_2 emissions is highly uncertain, it appears increasingly likely that such controls are coming, and that early action could translate into a competitive advantage. Indeed, they are almost universally regarded as necessary if we are to take the challenge of climate stabilization seriously.

Once mandatory CO_2 emissions limits are adopted at the regional or national level, and power plants were required to hold emissions allowances for CO_2 much as they must today for sulfur oxides, power plants could face very significant costs of compliance. If exchangeable with emissions allowances in the future, CO_2 emissions offsets acquired under an EFSEC CO_2 rule could provide an important economic asset.[7]

Consider, for instance, currently pending national legislation aimed at curbing GHG emissions, the Climate Stewardship Act (Senate Bill S.139), also referred to as the McCain-Lieberman bill. It creates a market-based cap-and-trade program to reduce emissions, patterned after the acid rain program of the 1990 Clean Air Act. As with the acid rain program, major emissions sources (including electricity generators) would be required to hold an allowance (or permit) for every ton of CO_2-equivalent emissions. The Climate Stewardship Act sets a target of reducing national GHG emissions to 2000 levels by 2010, and to 1990 levels by 2016, targets far less ambitious than the Kyoto Protocol (7% below 1990 levels by 2008-2012). Emissions sources would be allowed to use "off-system credits", i.e. offsets, from non-regulated US sectors (including smaller sources, forestry and agriculture) and a wide range of international sources to meet their emissions targets, similar to what might be purchased under an EFSEC CO_2 rule.[8] While the Climate Stewardship Act is viewed as having little chance under the current Congress, it is viewed as a setting the template for future legislation.[9]

2002 Draft. These include an all-inclusive capital cost of $617/kW, heat rate of 7030 btu/kWh, and availability of 92%, which I simplified to a 90% capacity factor. Remaining assumptions are documented in the accompanying spreadsheet.

[6] See, for example, Rabe, B. 2002. *Greenhouse & Statehouse: The Evolving State Government Role in Climate Change*, and Margolick, M. and Russell, D., 2001. *Corporate Greenhouse Gas Reduction Targets*, Prepared for the Pew Center on Global Climate Change, November. www.pewclimate.org

[7] If CO_2 permits were grandfathered to existing sources, as was done with SO_2, compliance costs would be far lower, but the value of offsets would be the same, since they would enable excess permits to be sold as a source of revenue.

[8] Note that "in-system" offsets, e.g. project activities that reduce emissions by major fuel users, could still maintain future value, depending on how the terms of the offsets contracts were negotiated.

[9] Pizer, W., Kopp, R, 2003. *Summary and Analysis of McCain-Lieberman – "Climate Stewardship Act of 2003"* Resources for the Future, January 28. www.rff.org/McCain_Lieberman_Summary.pdf

Two key elements of this legislation are particularly relevant for EFSEC deliberations:

- **Scope for offsets.** While the rules on allowable credits are not specifically defined in the legislation, it is reasonable to assume that credible and verifiable offsets – as might be purchased under the EFSEC rule – would be deemed eligible. It is unclear whether emissions reductions occurring prior to 2010 would count, but the legislation is generous with respect to crediting what is considered early action prior to this date.[10] Experience from other cap-and-trade systems (e.g. Kyoto Protocol and acid rain) suggests that offset-like instruments are likely to be recognized in CO2 emissions legislation, as it adds flexibility, lower compliance costs, and motivates action in non-capped sectors. Parallel efforts, such as the California Climate Registry and GHG Protocol, are also presently underway to help ensure that early actors, such as power plant developers buying offsets, will be rewarded under future regulation.
- **Projected allowance costs.** Several recent modeling studies have sought to estimate the future cost of allowances under the Climate Stewardship Act. Recent modeling runs by the US DOE suggest that allowances, under a scenario with considerable use of offsets, would cost $20/tCO2 in 2010 and $44/tCO2 in 2020.[11] MIT modeling studies suggest allowance costs ranging from $15/tCO2 up to $25/tCO2, under a similar scenario. While these estimates may be somewhat high for technical reasons[12], it is instructive to note that these values are nearly ten times the offsets today and projected over the rest of the decade ($3.00-$5.50/tCO2).

Overall there are four key factors that will determine the extent to which offsets purchased under the EFSEC CO2 rule might provide a future economic benefit

a) the **likelihood** of future CO2 emission caps
b) the **cost of allowances,** which is a function of how stringent this cap would be.
c) the **transferability** or validity of CO2 offsets purchased under the EFSEC rule under a future cap-and-trade system.
d) the **timing** of these caps, which will affect the risk and time value of the benefits

The risk management benefit provided by offsets is the product of these four factors.

A Scenario Approach to Assessing Risks

Scenario analysis provides a useful way to examine a situation with such speculative factors. In the section below, I will present three alternative scenarios. The first represents a situation where there is no tangible risk management benefit. CO2 emissions are either not to be capped during the operating lifetime of the power plant (e.g. by 2034), or if they are, offsets purchased

---

[10] In any case, a threshold date (e.g. 2010) would likely not pose a major concern, since offset contracts would likely generate emission reductions across the full 30 year life of the power plant, e.g. 2005-2034 in the case of a plant in service in 2005. It is likely that, at most, only a small fraction of offset-based emission reductions might be ineligible.

[11] These estimates are drawn from the Pew Center's review of S. 139 studies, available at http://www.pewclimate.org/policy/EIAanalysis.cfm, where they are presented in metric tons.

[12] See Pew Center report noted above and Bailie, A., Bernow, S., and Lazarus, M., (2003) *Analysis of the Climate Stewardship Act*, Tellus Institute, Boston.

today would have no value in this system.[13] The second scenario represents a situation where legislation akin to the Climate Stewardship Act is adopted, with emissions caps starting in 2010, average allowance costs of \$25/tCO2 (based roughly on the above DOE and MIT analyses), and full scope for including post-2009 offsets[14] purchased under an EFSEC rule. The third is an intermediate scenario, where doubts about likelihood of emissions caps, the future validity of offsets, and projected allowance costs, combine to yield a 40% probability of offsets being worth an average of \$25/tCO2 from 2010 onwards.

Under each of these scenarios, I calculate the "net" change in power plant costs resulting from an EFSEC CO2 standard. This net cost is simply the cost of acquiring offsets minus the risk management benefit of avoiding the need to buy emissions allowance under a future emissions cap, i.e.:

Net cost = Offset acquisition costs – (Avoided allowance costs x Probability of offset validity)

Scenario 1: No risk management benefit
Since under this scenario, the probability of offsets being valid instruments to reduce future allowance costs is zero by definition, the only major economic consideration is the cost of acquiring offsets.

Offset acquisition costs
To first order, calculating offset acquisition costs is relatively straightforward. It is simply the amount of CO2 emissions that need to be offset under a given target (17%, 40%, or 100%) times the assumed price strategy adopted by the rule -- e.g. the Oregon standard, an intermediate \$2/tCO2, or the full-market price, which we assume starts at around \$3/tCO2 today and increases to \$5.5/tCO2 by 2010. Divided by the total kWh produced, this yields the "simple, unfinanced" cost of offsets for a given power plant, as shown in Table 1. On this basis, a CO2 rule stating that 17% of emissions and using the Oregon price formula would appear to add one-hundredth of a cent or 0.2% to the 4.29 cents per kWh (c/kWh) "busbar" cost of producing a kWh of electricity from a new natural gas plant.[15] If all emissions from the plant were offset at the all-inclusive market price of offsets, then this simple approach suggests that offsets would cost an average of 0.15 c/kWh, adding 3.6% to cost of production.

[13] The latter would be equivalent to the "double jeopardy" situation, from a developer's perspective, presented by Dr. Mark Trexler at the EFSEC public hearing.
[14] Future legislation could very well grandfather offsets booked prior to this year – and indeed various climate registry and baseline protection efforts are aimed at this goal – thereby increasing the benefit (i.e. fully rewarding offsets from 2003 through the first compliance date) beyond what is assumed here.
[15] All costs are levelized across the typical 20-year amortization period of a new plant investment. Levelized natural gas costs are projected to be \$3.70/MBtu, based on recent NW Power Council medium case estimates.

Table 1. Cost of offsets, simple, unfinanced (cents/kWh)

Price (in 2005)	Stated offset requirement		
	17%	40%	100%
Oregon ($1.3/tCO2)	0.01c *(0.2%)*	0.02c *(0.5%)*	0.05c *(1.2%)*
Int. ($2.0/tCO2)	0.01c *(0.3%)*	0.03c *(0.8%)*	0.08c *(1.9%)*
`All-in' market ($3.7/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

However, the simple approach may underestimate costs, since it presumes that developers would be able to make the five-year upfront offset payments from available cash. It is more likely that the offset requirement will increase developers' financing requirements. Financing of offset payments, in turn, would roughly double the cost of offsets, as shown in Table 2.[16] At the 40% offset requirement and intermediate price of $2/tCO2, financing of offset payments would add 0.06c/kWh (1.4%) compared with 0.03c/kWh (0.8%) in the simple, unfinanced case.

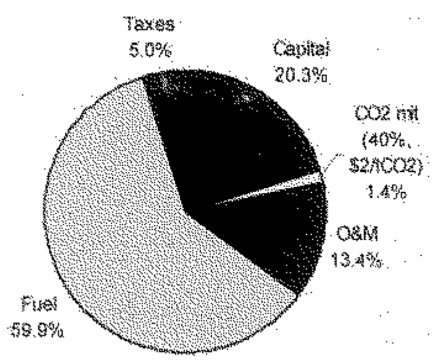
Table 2. Net change in new power plant costs, Scenario 1 - no avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement		
	17%	40%	100%
Oregon ($1.3/tCO2)	0.02c *(0.4%)*	0.04c *(0.9%)*	0.10c *(2.3%)*
Int. ($2.0/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*
`All-in' market ($3.7/tCO2)	0.05c *(1.1%)*	0.11c *(2.7%)*	0.29c *(6.7%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Figure 1 shows how this 0.06c/kWh offset cost compares with other cost components of a new natural gas plant. Not surprisingly, fuel costs are predominant, and are also highly uncertain, especially in light of price surges and concerns echoed by Federal Reserve chairman Alan Greenspan. If instead of the NPPC's medium gas forecast shown here ($3.70/MBtu levelized 2005-24), their high estimate were realized ($4.56/MBtu, levelized), the cost of electricity production would rise by 0.60 c/kWh, roughly ten times the magnitude of the offset cost imposed under a 40% /$2 mitigation requirement.

Figure 1. Annualized costs for a 540 MW natural gas CCCT



[16] For the purposes of this calculation, I assume that offset payments will be financed on a similar basis as other power plant investments (20 year amortization), except that financing is purely on a debt basis (at 8.7% nominal interest rate).

Box 1. Reflecting actual mitigation amounts

It is important to not that fixing a price below the market cost of offsets effectively reduces the emissions actually mitigated, as is well recognized in the Oregon case. Since the Oregon price (e.g. \$1.28/tCO2 in 2005) is likely to cover only 34% of the total costs of acquiring offsets (including the administrative costs), under a 17% standard only 6% of emissions would actually be mitigated. At a \$2/tCO2 price and a 40% standard only 22% would be mitigated. It is important to be explicit this potential discrepancy, so the actual benefits are properly stated and to maximize credibility of the proposed rule. (See Table 3) Any discrepancy in initial price setting is also likely to magnified should offset price escalation be limited to a standard economic price index (such as CPI, PPI), since offset prices are likely to increase much faster than inflation.

Table 3. Actual "mitigation" or offsets purchased given lower-than-market prices

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon (\$1.3/tCO2)	6%	14%	34%
Int. (\$2.0/tCO2)	9%	22%	54%
'All-in' market (\$3.7/tCO2)	17%	40%	100%

Consumer rates

Increased costs would be reflected either in higher electricity rates or in lost profits by power plant owners. Private and public utility owners would be able to pass on costs to consumers directly, whereas merchant power plant developers would likely absorb much of the added cost in lost profits until a significant fraction of the market is subject to similar costs. Assuming, however, that all offset costs were somehow passed on to consumers, I estimate that by 2010 that rates would rise by from two thousandths of a cent (17% target, Oregon price) to three hundredths of a cent (100% target, full market price), as shown in Table 4.[17]

[17] For the purposes of this calculation, I have assumed that all growth in demand in the Pacific Northwest -- projected to be about 200aMW per year -- is met by new natural gas CCCT plants subject to the CO2 rule. Using this assumption about 8% of generation is subject to this charge in 2010, while about 14% is by 2020. These assumptions are likely to significantly overstate the amount of natural gas capacity built, given competition from other sources of supply within and outside the region. At the same time, however, some capacity may be built in the region for the purposes of displacing older or more costly sources throughout the West.

Table 4. Change in consumer rates, 2010, Scenario 1 - no avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.002c *(0.0%)*	0.004c *(0.1%)*	0.010c *(0.2%)*
Int. ($2.0/tCO2)	0.003c *(0.0%)*	0.006c *(0.1%)*	0.015c *(0.3%)*
'All-in' market ($3.7/tCO2)	0.005c *(0.1%)*	0.011c *(0.2%)*	0.028c *(0.5%)*

Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Assuming built 2005-2010, subject to increasing offset prices
Assuming current average rate of 5.3c/kWh

Under the 40% target and $2/tCO2 case, rates would rise about 0.006 cents, and average monthly bill would go up 8 cents for the average household, 53 cents for the average commercial customer, and $5.52 cents for the industrial customer (See Table 8 below). By 2020, these effects would just about double.

Scenario 2: Full risk management benefit
Just as the first scenario represents the most pessimistic, this scenario reflects the most optimistic outlook for recovering offset investments in the form of avoided future allowance costs. In this case, if we assume that all offsets purchased under an EFSEC rule are considered valid and interchangeable with emissions allowances under a future cap-and-trade system, at an average value of $25/tCO2 from 2010 onwards, these offsets take on a significant financial value, as shown in Table 5.

Table 5. Full value of offsets under a future cap-and-trade system (c/KWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.04c *(1.0%)*	0.10c *(2.3%)*	0.25c *(5.9%)*
Int. ($2.0/tCO2)	0.07c *(1.6%)*	0.16c *(3.7%)*	0.39c *(9.2%)*
'All-in' market ($3.7/tCO2)	0.12c *(2.9%)*	0.29c *(6.8%)*	0.73c *(17.1%)*

At 25/tCO2 allowance price, 2010 onwards
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Offsets in this case are worth from 0.04 to 0.73 cents per kWh[18], and when subtracted from the cost of buying the offsets, the net effect on electricity costs drops from 0.6% to 10.3%, as shown in Table 6. At a 40% target and $2/tCO2 price, the long-term cost of electricity drops by a tenth of a cent or 2.2%, and the maximum impact of consumer rates would be a drop of about 0.1% (see Table 8).

[18] Avoided compliance costs are discounted back to 2005 and levelized across the life of the power plant.

Table 6. Net change in new power plant costs, Scenario 2 - full avoidance of compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	-0.03c -(0.6%)	-0.06c -(1.4%)	-0.15c -(3.6%)
Int. ($2.0/tCO2)	-0.04c -(0.9%)	-0.10c -(2.2%)	-0.24c -(5.6%)
'All-in' market ($3.7/tCO2)	-0.08c -(1.8%)	-0.18c -(4.1%)	-0.44c -(10.3%)

Assuming full transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Scenario 3: Partial risk management benefit
The third scenario represents an intermediate case, recognizing that neither the pessimistic "Scenario 1" or optimistic "Scenario 2" outlook for the future value of offsets is likely to be correct. The precise likelihood and magnitude of offsets value depends on the many factors described above: likelihood of a cap, its stringency and resulting CO2 permit costs, the fungibility of offsets in this system, and ultimately the perceived quality of offsets themselves. Thought these are highly uncertain factors, EFSEC is not without influence. State and local actions, such a meaningful EFSEC CO2 rule, create increased pressure for national emissions caps. And EFSEC rules for how offsets are acquired will inevitably affect their perceived quality.

As illustrated in the Table 7, if one assumes that, on average, offsets acquired under an EFSEC rule have a 40% probability of being worth $25/tCO2 from 2010 onwards, then the avoided compliance costs roughly cancel the costs of buying offsets, and the rule has no net overall economic impact.

Table 7. Net change in new power plant costs, Scenario 3 - some avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.00c (0.0%)	0.00c (0.0%)	0.00c (0.0%)
Int. ($2.0/tCO2)	0.00c (0.0%)	0.00c (0.0%)	0.00c -(0.1%)
'All-in' market ($3.7/tCO2)	0.00c (0.0%)	0.00c (0.0%)	-0.01c -(0.1%)

Assuming 40% transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Assuming costs and benefits are passed on equally to consumers, there is, not surprisingly, there would be almost no effect on consumer bills, as shown in Table 8 below. Together these three scenarios can be thought of as bracketing the range of impacts this rule would have, under the assumptions used here.[19]

[19] An accompanying spreadsheet is available for reviewing all assumptions and conducting sensitivity analyses.

Table 8. Monthly bill impact, 2010, assuming \$2/tCO2, 40% requirement

Price (in 2005)	Residential	Commercial	Industrial
Scenario 1 - No risk management benefit	\$0.08	\$0.53	\$5.52
Scenario 2 - Full risk management benefit	-\$0.10	-\$0.65	-\$6.72
Scenario 3 - Partial risk management benefit	\$0.00	-\$0.01	-\$0.08

Based on USDOE data for WA rates and average bills by class, 2001
Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Actual savings in Scenarios 2 and 3 will be lower than shown to the extent compliance costs are lower in early years of cap-and-trade system.

Conclusions
As is clear from its extensive questions and deliberations with public stakeholders, EFSEC is considering many potential options and outcomes with respect to its proposed CO2 rule. In keeping with this broad view, EFSEC commissioners may wish to consider how these options might interact with serious federal action to address the climate problem. Many observers are convinced that mandatory US emissions caps are, if not inevitable, at least required if we are to take the challenge of climate stabilization seriously. However, there is great uncertainty as to when they will be adopted, how stringent they will be, their cost implications, and the extent to which offset investments made under an EFSEC rule would be deemed creditable towards future emissions targets. As this analysis shows, resolution of these uncertainties is central to how the economics of this rule will ultimately play out.

Under the most pessimistic scenario (#1) for federal action under which EFSEC-approved offsets would have no added financial value, the costs of power from a new natural gas plant would rise from 0.4% (17% target/OR price) to 6.7% (100% target/market price). Under a 40% target and \$2 price strategy, the new power cost would rise 1.4%, and, if the added costs were passed on to consumers, electric rates would rise by 0.1% by 2010, adding 8 cents to the average monthly household bill, 53 cents and \$5.52 for the average commercial and industrial customers, respectively. Other uncertainties, such as the cost of gas or the fate of electricity restructuring are likely to have a much more significant impact on consumer costs.

Under the most optimistic scenario (#2) for recovering offset investments – assuming they can count almost fully against future emissions allowances costing at average of \$25/tCO2 from 2010 onwards – a proposed EFSEC rule would actually reduce consumer rates and increase developer profits over the long run. In 2010, the average household bill might actually be 10 cents lower, and commercial and industrial customers might see a drop of 65 cents and \$6.72, respectively, assuming a 40% target and \$2/tCO2 fixed price.

Under an intermediate scenario (#3), where the combined probability of having a mandatory emissions cap-and-trade system and of EFSEC-required offsets being valid under that system comes to about 40%, the effect on power plant costs and rates is roughly a wash. This breakeven point is equivalent to assuming that from 2005 onwards emissions from all new plants will pose a liability of about \$9/tCO2. This metric is similar to what Pacificorp already uses for planning purposes; its recent Integrated Resource Plan assumed that new fossil plants will have to pay

\$8/tCO2 emitted.[20] Both of these values reflect attempts to quantify three of the four key uncertainties noted above: the likelihood of future emissions caps, timing and extent of these caps, and the price of emissions allowances under such a cap. The other uncertainty, which is not addressed in Pacificorp IRP analysis, is the fungibility of EFSEC-required offsets in a cap-and-trade system.

To maximize future offset value, I strongly recommend that EFSEC create a process that encourages best practice on key issues such as baselines and additionality, leakage and permanence, and monitoring and verification. In this regard, EFSEC can look to standards being developed by the Executive Board of the Clean Development Mechanism, by the World Resources Institute and World Business Council for Sustainable Development, who will soon release their first GHG Protocol for project-based activities, and by the California Climate Registry. In addition, there are the many lessons learned by Climate Trust, Seattle City Light, and the Oregon Office of Energy.

The future liability posed by CO2 emissions from new, long-lived power plants may be very significant. If owners of 540 MW NG CCCT in service in 2005, were required to hold emissions allowance for each ton of CO2 emitted at an average of \$25/t from 2010 onward through its 30 year life, the net present value of this liability would come to \$380 million (NPV), exceeding the total cost of the plant investment itself (about \$330 million). This suggests that the less investment in mitigation done now, the greater the potential future liabilities.

This analysis has focused on a very narrow conception of economic costs and benefits – those related directly to the price of electricity production and use. However, regardless of whether one includes the liabilities for future emissions are counted in the balance sheet, they represent real economic costs to society at large, the hard-to-quantify damages from an incrementally altered climate.

[20] Pacificorp's IRP assumes a base case wherein CO2 allowance costs are \$8/tCO2 starting in FY2009. http://www.pacificorp.com/File/File25682.pdf

bp

BP Cherry Point Refinery
4519 Grandview Road
Blaine, Washington 98230
Telephone 360 371-1500

RECEIVED

NOV 0 3 2003

ENERGY FACILITY SITE EVALUATION COUNCIL

Irina Makarow
EFS Specialist
PO Box 43172
Olympia, WA 98504-3172

Re: DEIS Comments

October 31, 2003

Dear Ms. Makarow

Thank you for the opportunity to comment on the BP Cherry Point Cogeneration Project Draft Environmental Impact Statement (DEIS) DOE/EIS-0349. We believe that the DEIS provides a fairly good description of the proposed project and its potential environmental impacts (or lack thereof). We agree wholeheartedly that the proposed project will not have any significant adverse environmental impacts. We have two general comments regarding the document. 1

Our first general comment concerns the "No Action Alternative." Chapter 2 describes the No Action Alternative, and then the various sections of Chapter 3 compare the potential environmental impact of the proposed Cogeneration Project to those of the No Action Alternative. In order for the comparison of environmental impacts to be complete and accurate, however, the No Action Alternative must be properly described. Under the No Action Alternative, although the Cherry Point Cogeneration Project would not be constructed, other electrical generating facilities would need to be constructed and operated to meet growing regional electricity demand over time. Such facilities would be expected to have the same sorts of potential environmental impacts as the proposed Cogeneration Project (e.g. air emissions, CO2 emissions, water use, construction related impacts). However, the facilities providing power under the no action alternative facilities are not likely to be cogeneration facilities or to have the other advantages that the Cogeneration Project has by virtue of its integration with the refinery's existing infrastructure. Among other things, these other facilities are likely to emit more air pollutants and CO2 emissions, use more water use, burn more fuel and have more impacts associated with constructing related infrastructure and facilities. Throughout the document, the DEIS should make clear that the same amount of electricity would be generated by different facilities under the No Action Alternative, and as a result, the No Action Alternative would have more impact on the environment than the proposed Cogeneration Project. 2

Our second general comment concerns the "additional recommended mitigation" found in the DEIS. Under the State Environmental Policy Act (SEPA), recommendations for additional mitigation should be tied directly to significant impacts identified in the DEIS, and should be based upon regulations or policies formally adopted by the action agency pursuant to SEPA. The DEIS does not justify the recommendations of additional mitigation as required by law.

In addition to these general comments, we are enclosing a list of specific comments. Many of these comments are minor, pointing out typographical errors or correcting statements describing the proposed project, but others address more substantive concerns. In each case, we have tried to identify the specific section, page and paragraph to which our comment relates. 3

BP Cherry Point Refinery
Page 2

Please do not hesitate to contact me if you have questions regarding any of these comments, or if you need additional information to complete the Final EIS.

Sincerely,

Mike Torpey
Environmental Team Lead
BP Cherry Point Cogeneration Project
4519 Grandview Road
Blaine, WA 98230

360-371-1757

.cc
Karen McGaffey
Mark Moore
Wolfgang Nuehoff

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
1	MDT	1-4	1.2.1	4	5		The boiler efficiency provided in the application was 85%. However, 83% efficiency is the actual boiler efficiency and 83% efficiency was used for the boiler emission calculations.	3(1)
2	KM	1-7	1.4.1	1	1		The total project area should be 194-acres. If the DEIS is going to use 265-acres, then it should also state that the BPA transmission line ROW from the interconnection to the Custer substation is included in the total acreage.	3(2)
3	WJR	1-7	1.4.1	6		new	Add "Emergency Firewater Pump" to the bullet list.	3(3)
4	MDT	1-7	1.4.1	5		new	Add "Water Treatment Facilities" to the bullet list	3(4)
5	TS	1-7	1.4.1	5		5	Change "150 MVA step-down transformer" to "185 MVA nominal step-up transformer"	3(5)
6	TS	1-7	1.4.1	5		new	Add "One 275 MVA step-up transformer" to the bullet list.	3(6)
7	MDT	1-11	1.4.2	1	2	new	Cogeneration makes this project a more efficient producer of electricity than a standalone gas-fired combined cycle combustion turbine plant. Because the opportunities for cogeneration are limited, If this plant were not built, then another less efficient plant would be built within the region to supply the growing demand for electricity. A standalone plant would use more water, produce more air emissions, produce more green house gasses, and use more fuel per kWh of electricity produced.	3(7)
8	KM	1-13	1.6.3	1	4		Delete the last sentence and replace it with the following, "The Ferndale Pipeline would supply gas for the new Cogeneration Plant and the Refinery. If additional gas is needed during periods of peak Refinery demand, then Cascade Natural Gas would provide/transport supplemental gas to the project."	3(8)
9	KM	1-14	1.6.8	2		1	230 KV Switchyard - The cogeneration facility would own about 65% of the switchyard and BPA wold own about 35%. BPA's portion is just that part of the switchyard that allows the output of the plant to be routed to BPA's grid.	3(9)
10	KM	1-14	1.6.8	2		2	Industrial Water Supply - We expect Whatcom PUD to build, own and operate the water supply line up to the Cogeneration Project boundary. The new pipeline connection would start at the southeast corner of the Refinery and run parralel to the existing Refinery supply line along Blaine Road.	3(10)
11	KM	1-14	1.6.8	2		3	Natural Gas Suppply and Compressor Station - The Cogeneration Plant would own and operate the natural gas compressor station located inside the Refinery.	3(11)
12	KM	1-14	1.6.8	2		4	Intermediate Voltage Substation - The Refinery would build the 230 KV to 12.5 KV substation adjacent to the existing MS3 substation on an existing graveled pad.	3(12)
13	KM	1-15	1.6.8	3		1	Refinery Interface Piping Systems - The Refinery would build an elevated pipeway to carry process streams such as steam and condensate between the two facilities. The pipeway would cross the utility corridor between Blaine Road and the Cogeneration boundary on a series of pipe supports called "sleepers". The length of the pipeway in this corridor is about 630 ft. The supports are placed on 37 concrete foundations constructed, which consist of two 2-foot by 2-foot concrete pedestals.	3(13)
14	KM	1-15	1.6.8	3		2	Custer/Intalco Transmission System - Modifications to this transmission system will be built, owned, and operated by BPA. BPA should supply this informaton.	3(14)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
15	TS	1-18	1.6.8	Table 1-2	Contruction	2	Delete second bullet. The site was surveyed for contamination during the geotech survey and no contamination was found. Sampling is not planned during clearing, grading, and trenching. However, if contamination is found during these activities, then clearing, grading and trenching would be halted until the contamination could be safely dealt with.	3(15)
16	KM	1-19		Table 1-2	Operation		Additional Mitigation Measures - We do not agree with the additional mitigation measure proposed. The facility would evaluate the potential impacts of tephra fall out and take appropriate action with regard to plant operations.	3(16)
17	WJR	1-19		Table 1-2	Operation	1	Add "or WAAQS" after NAAQS at the end of the sentence.	3(17)
18	KM	1-20		Table 1-2	Operation	1	Delete and then add, "Use appropriate measures to reduce particulate matter while transporting material in trucks, which may include covering and wetting."	3(18)
19	KM	1-20		Table 1-2	Operation	2	Delete and then add, "Use appropriate meaures to reduce and remove particulate matter from wheels before entering roads, which may include wheel washers."	3(19)
20	KM	1-20		Table 1-2	Operation	4	Delete and then add, "Maintain construction equipment in good working order to reduce CO and NOx emissions."	3(20)
21	WJR	1-20	1	Table 1-2	Operation	1	Add "or Washington Ambient Air Quality Standards" after "National Ambient Air Quality Standards" at the end of the sentence.	3(21)
22	WJR	1-21		Table 1-2	Operation		No Action Alternative - The Refinery would continue to operate utility boilers, new less efficient power plants would be built elsewhere in the region with higher air emissions and higher greenhouse gas emissions, higher water useage, and use more fuel per kWh.	3(22)
23	KM	1-27		Table 1-2	Operation	10	Additional Recommended Mitigation Measure - We do not understand what is being recommended by this item. The plant surface will be mostly concrete and gravel. There will be areas of landscaping, which will be maintained to keep noxious weeds from spreading.	3(23)
24	KM	1-36		Table 1-2	Operation	1	Delete "An eastbound and" The application specifies only a westbound turn lane.	3(24)
25	KM	1-36		Table 1-2	Operation	3	Delete "...Blaine Road/Grandview Road (SR548).." No signal is planned at the Blaine Road/Grandview Road Intersection. Move this entire bullet item to the Mitigation Measures Proposed by the Applicant.	3(25)
26	MDT	2-6	2.2.2	1	1		195 acres, not 265 acres (33+15+36+110) unless it is stated that the Transmission line corridor is from the interconnect to the Custer Substation iss included in the acreage.	3(26)
27	MDT	2-6	2.2.2	3		new	Add "Emergency Fire Water Pump" to the bullet list	3(27)
28	MDT	2-6	2.2.2	3		new	Add "Water Treatment Facilities" to the bullet list	3(28)
29	TS	2-6	2.2.2	5			Change "150 MVA step-down transformer" to "185 MVA nominal step-up transformer"	3(29)
30	TS	2-6	2.2.2	5		new	Add "One 275 MVA step-up transformer"	3(30)
31	TS	2-8	Table 2-1	5	1		Change 'universal' to "uninteruptable"	3(31)
32	MDT	2-10	Table 2-1	MS1			New Low Voltage Switchyard near MS 3 only	3(32)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
33	TS	2-10	Table 2-1	2			The decription of the high voltage swtichyard in the DEIS accurately represents the switchyard we described in the application, however, the follow describes our current thinking. We'll leave it up to EFSEC/Shapiro to determine if description in the DEIS needs to be changed. "The 230 kV switchyard will be a breaker and a half arrangement. The BPA interconnect will be two 230 kV receiving structures and four (4) 230 kV circuit breakers and eight (8) disconnects switches and associated metering, protection, control and communication. The Project interconnection to the switchyard will include four (4) 230 kV receiving structures for GSU interconnections and two (2) 230 kV receiving structures for Refinery interconnection. The remaining eight (8) circuit breakers, 24 disconnect switches and associated protection, control and communication. This results in a split of approximately a 35% BPA and 65% Project.	3(33)
34	TS	2-13	Table 2-2				The following tank sizes in the DEIS are correct, but the following represents our current thinking. We'll leave it up to EFSEC/Shapiro to determine if the tank sizes need to be modified in the application. "Condensate storage tank 600,000 not 500,000; Demineralized Water storage tank is 200,000, not 100,000; Wastewater equalization tank is 500,000, not 400,000 and Filtered water & firewater storage tank is 500,000 not 425,000."	3(34)
35	MDT	2-18	2.2.2	1	8		The rewrite the sentence to read, "The detention pond would be constructed as an unlined pond." Because the stormwater routed to this pond is uncontaminated rain water, ground water would not be affected.	3(35)
36	TS	2-18	2.2.2	2	2		Rewrite the second sentence as follows, "Storm water contained in secondary containment areas would be evaluated prior to discharge. If the water is uncontaminated, then it would be routed to the Stormwater system. If the water is contaminated, then it would be rouited to the Refinery Wastewatwer system."	3(36)
37	KM	2-19	2.2.2	5	4		This sentence states that the "maximum" water use will be approximately 2,780 gpm. That's not correct. The maximum amount of once through cooling water available from Alcoa is 2,780 gpm. The average use by the Cogen project will be 2,244 to 2,316 gpm, but the maximum instantaneous use could be higher than 2,780 gpm.	3(37)
38	MDT	2-26	2.2.2	4	2		Change "CMA1" to "CMA2". The project site detention pond will discharge to CMA2.	3(38)
39	MDT	2-27	2.2.2	3	4		Delete, "…,and would meet WSDOT and emergency vehicle requirements." Access road #3 was not intended to meet WSDOT and/or emergency vehicle access requirements.	3(39)
40	MDT	2-28	2.2.3	4	2		Rewrite the sentence, "The Application for Site Certification indicates that pile-supported concrete foundations would be used for all major equipment items and major buildings." Delete the reference to the steam turbine now being the only structure to be supported on piles.	3(40)
41	MDT	2-29	2.2.3	2	6		Change "6 to 10 feet deep" to "5 feet deep"	3(41)
42	MDT	2-29	2.2.3	2	7		Change "3 to 4 over the pipe" to "sufficient to bring the trench level up to original grade"	3(42)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
43	MDT	2-30	2.2.3	2	1		Change "150-foot" to "125-foot". While 150 ft was used in the application, the ROW will be as wide as BPA requires. We believe this will be 125 ft.	3(43)
44	TS	2-35	2.2.4	3	1		Rewrite the sentence to read, "While the cogeneration facility is generally designed to allow maintenance to occur without a complete plant shutdown, maintenance on mechanical parts of the steam turbine generator will most likely require a complete plant shutdown."	3(44)
45	MDT	2–40	2.4.1	5	1		Add, " Site 2 also interferes with future refinery modifications. Future refinery process units, such as isomerization and clean diesel units, require a much greater level of interconnection than the cogeneration facility. Because of the the interconnections, these process units require must be located very near existing process areas."	3(45)
46	TS	3.1-19	3.1.5	1	1		Delete first sentence and add, "The site was surveyed for contamination during the geotech survey and no contamination was found."	3(46)
47	MDT	3.2-3	3.2.1	Table 3.2-1		SO2	Delete the National three-hour primary standard for SO2 0.14. There is no national three-hour primary standard for SO2	3(47)
48	WJR	3.2-3	3.2.1	Table 3.2-1	Ozone		The eight-hour ozone standard is "157 ug/m^3" not "176 ug/m3"	3(48)
49	MDT	3.2-17	3.2.3	5	1		Delete "including background". The concentrations shown in table 3.2-9 are strictly modeled concentrations without background.	3(49)
50	WJR	3.2-18	3.2.3	2	1		Rewrite the sentence to read, "The Industrial Source Complex Prime (ISC Prime) dispersion model was used."	3(50)
51	BRP	3.2-19	3.2.3	Table 3.2-11			Change the SO2 standard for annual and 24-hour from "80" and "365" to "53" and "260" The new numbers are the WAAQS, which are more restrictive then the NAAQS.	3(51)
52	WJR	3.2-19	3.2.3	Table 3.2-11			Please change the 1-hour SO_2 standard from "1,065" to "1,050"	3(52)
53	MDT	3.2-19	3.2.3	1	6		Modify the sentence to read, "Also, the modeling results show that the annual maximum concentration of NO2 is 0.0053 ug/m3, which is well below the SIL of 0.1ug/m3."	3(53)
54	BRP	3.2-19	3.2.3	1			Add a sentence at the end of the paragraph, "Both the modeled concentrations of PM and SO2, annual and 24-hour are well below the respective SIL's in class I areas."	3(54)
55	MDT	3.2-28	3.2.3	Table 3.2-20	PM10	Net	Change "-84" to "84" The sign was entered incorrectly. We are providing a new table, which includes the effects of the changes in Molecular weight on the over all balance. This change makes the balance more complicated, but it is also more accurately describes the actual particulate balance.	3(55)
56	BRP	3.2-31	3.2.3	Table 3.2-23			New table provided with Molecular weight conversion	3(56)
57	BRP	3.2-33	3.2.3	5	2		Delete the last sentence and add, "Cooling tower modeling shows that icing will not occur."	3(57)
58	KM	3.2-34 to 3.2-35	3.2.5				The "Regulatory Framework" discussion and summary of mitigation requirements is incomplete and potentially misleading. In addition to listing the four Washington projects for which EFSEC has required greenhouse gas mitigation, the EIS should clearly state that no other operating or permitted facilities in Washington are subject to any greenhouse gas mitigation requirement.	3(58)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
59	KM	3.2-35	3.2.5	last 2			The "Project Greenhouse Gas Emissions" discussion is incomplete. An EIS should discuss the impact of the proposed project in comparison to the "no action alternative." Under the no action alternative, growing regional electric demand would be met by generating facilities other than the Cogeneration Project. Those facilities would be less efficient and more GHG-intensive than the Cogeneration Project. Therefore, operation of the Cogeneration Project would result in fewer GHG emissions than would occur under the no action alternative. It is for this reason that virtually every authority on global warming and GHG emissions recommends the increased reliance on gas-fired combined cycle combustion turbine facilities, and cogeneration facilities in particular, as an important near-term solution to rising GHG emissions.	3(59)
60	KM	3.2-35	3.2.5	last 2			In his Direct Testimony, which BP filed with EFSEC on September 19, 2003, W. David Montgomery (an internationally recognized expert on the economics of GHG reduction) estimates that the operation of the Cogeneration Project will result in 320,000 tons less CO2 being emitted compared to the No Action Alternative.	3(60)
61	KM	3.2-35	3.2.5	last ¶	2		The statement "Fugitive leaks of natural gas from the systems serving the proposed cogeneration facility are estimated to emit methane equivalent to 12% of the project's stack emissions of greenhouse gas" is not appropriate. Leaks of methane that occur at various places in the North American natural gas pipeline system are not directly related to the Cogeneration Project and are certainly not caused by the Cogeneration Project. If the Cogeneration Project were not built, natural gas would be transported to other electrical generating facilities, and system-wide transportation losses would occur in any event. If leaks are occurring in the pipeline system, it is the responsibility of entites that own and operate that system to address those leaks and mitigate them as appropriate.	3(61)
62	BRP	3.2-38	3.2.6	5	last		Please add the following sentence, "These receptors are not near the BP Cherry Point Cogeneration Project site and not effected by the Project emissions."	3(62)
63	BRP	3.2-39	3.2.6	1	2		"100 out of 18" should probably be "10 out of 18".	3(63)
64	WJR	3.2-39	3.2.6	1	2		Add a sentence at the end of the paragraph which reads, "These receptors are not near the Cherry Point Project site and are not impacted by the Cherry Point Project emissions."	3(64)
65	KM	3.2-42	3.2.6	5	6		The statement "the production of greenhouse gases could be reduced if operation of the BP cogeneration facility displaces the operation of other non-cogeneration faciltiies" is incomplete and may confuse the reader. It should go on to state that, in the region's competitive wholesale power market, power plants operate according to their merit order of cost and efficiency. Therefore, BP's cogeneration facility would displace less efficient and greater-emitting facilities. Please see the Direct Testimony of James Litchfield, W. David Montgomery, and Mark Moore filed with EFSEC by BP on September 19, 2003. In particular, David Montgomery estimated that operation of the BP facility would result in a decrease in CO2 emissions of 320,000 tons per year.	3(65)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
66	BRP	3.2-44	3.2.6	Table 3.2-28			The SO_2 24-hour impact at Abbotsford is 0.058 not 0.58.	3(66)
67	BRP	3.2-44	3.2.6	Table 3.2-29	SO2		Please change the standards for SO_2 annual and 24-hour from "80" and "365 to "53" and "260". The 53 and 260 numbers are WAAQS's and more restrictive than the NAAQS.	3(67)
68	WJR	3.2-44	3.2.6	Table 3.2-29	SO2		Please change "1,065" to "1050" for the 1-hour SO_2 standard.	3(68)
69	KM	3.2-45	3.2-7			7	Delete the bullet under additional recommended mitigation measures. Add, "Appropriate measures will be carried out to minimize PM due to the transport of material in trucks."	3(69)
70	MDT	3.2-46	3.2.7	3			Delete the paragraph and add "The Refinery has committed to removing the three older boilers within six months of beginning commercial operations."	3(70)
71	KM	3.2-46	3.2.8	6	4		The statement "The various analyses . . .indicate that air emissions associated with the proposed cogeneration facility would occur and would have an impact on the overall air quality of the region" is misleading, if not factually incorrect. The statement suggests that the project will have a noticeable impact on air quality throughout the region, but the analyses demonstrate the opposite. Even without taking into account the reductions in emissions at the refinery that will occur as a result of the cogeneration project, the modeling analyses indicate that the facility emissions will have a negligible effect on ambient concentrations of regulated pollutants in the region. Even the maximum modeled impacts at the maximum point of impact are below the "significant impact levels" or SILs established by the Department of Ecology. Modeled impacts diminish rapidly as you move away from the facility. It would be more accurate to say that the analyses indicate that the project will "have no practical effect on the overall air quality of the region."	3(71)
72	MDT	3.3-21	3.3.2	3	8		Delete and rewrite as follows, "To the extent possible, construction of the storm drainage facilities for the laydown areas would occur when the ground is dry enough to work efficiently."	3(72)
73	MDT	3.3-22	3.3.2	4	5		Delete and rewrite as follows, "To the extent possible, construction of the water reuse facilities would occur when the ground is dry enough to work efficiently."	3(73)
74	MDT	3.3-23	3.3.2	2	3		In response to concerns about wetland C. The proposed ditch is on the downslope side of the wetland and could only drain the edge near the ditch unless the ditch intercepted a low spot in the wetland. Our approach is to use the new 1-foot contour map (and site work as necessary) to fine-tune the design of the perimeter ditch. The fundamental idea will be to keep it close to the existing elevation of the wetland to prevent draining just because of elevation difference (the drainage ditch concept). The width will be varied to manage the anticipated volume at any given point along it. If necessary, a berm will be placed on the powerplant side of the ditch to make sure the water can't escape across the site. Where the pad for the site is already elevated above the wetland, it will form a natural berm, and the only thing necessary will be to make sure the edge of the pad is impervious enough to prevent seepage from making the pad unusable. If the ditch crosses a low spot in the wetland, it may be necessary to berm the wetland side of the ditch for its distance across the low spot. With this fine-tuning, all potential f	3(74)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
75	KM	3.3-23	3.3.2	5	2		There's a typo. It should read that Alcoa will provide approximately "2,780 gpm", not "2,770 gpm"	3(75)
76	MDT	3.3-28	3.3.5	5			Please add, "The project is considering a septic system as an alternative to routing sanitary sewer to the Birch Bay Water and Sewer District."	3(76)
77	MDT	3.4-14	3.4.2	2	7		Delete the sentence regarding the requirement to perform a ground water evaluation. Stormwater will be collected from uncontaminated areas of the project site and would have no effect on the groundwater.	3(77)
78	MDT	3.5-13	3.5.2	3	1		Replace "5" with "4". Only four transmission line towers are required.	3(78)
79	MDT	3.6-2	3.6.1	Table 3.6-1		Interface	The Refinery Interface Area would not be designated as "Open Space" and should be labeled "no" under the Open Space Column.	3(79)
80	MDT	3.7-23	3.7.2	4	1		Change "five" to "four". Only four new towers are required.	3(80)
81	MDT	3.7-23	3.7.2	4	4		Change "five" to "four". Only four new towers are required.	3(81)
82	MDT	3.7-35	3.7.5	1	4		Add to the last sentence, "...during initial clearing activities." After then site is cleared and graveled, the requirement to clean all equipment before leaving the site should end.	3(82)
83	KM	3.9-2	3.9.1	2	2		The statement than an increase of "3 to 5 dBA will be noticeable to most people" is not accurate without qualification. Although it may be possible for most people to discern a 3 to 5 dBA change in a laboratory setting, most people will not notice a change of less than 5 dBA in the real world. See Pre-filed Direct Testimony of David Hessler filed with EFSEC on September 29, 2003 at page 8 (A 5 dBA "increase is commonly described as barely being perceptible with careful listening").	3(83)
84	KM	3.9-6	3.9.2	4	1		The statement "some of the residential receptors' existing noise levels are shown to exceed the regulatory limit outlined in WAC 170-60," reflects a misunderstanding of the noise regulations. As correctly explained on page 3.9-2 of the DEIS, the Washington noise regulations apply to a single source of noise, rather than limiting the cumulative amount of a noise at a particular location. Therefore, it is not appropriate to say that the existing cumulative noise levels at a particular location exceed the regulatory limit. The question is whether a single specific source of noise causes sound levels to exceed the regulatory limits at the particular location.	3(84)
85	MDT	3.9-9	3.9.3	Table 3.9-5			Daytime/nighttime limits are compared against modeled plus background. This table should only compare modeled noise levels to the regulatory limits. For the same reason as above.	3(85)
86	MDT	3.9-12	3.9.6			2	Delete bullet 2. The project would agree to maintain construction equipment in good working order, but it would not agree to add additional noise attentuation features that were not already part of the original equipment.	3(86)
87	MDT	3.9-12	3.9.6			3	Delete bullet 3. The project would agree to use equipment that is maintained in good working order. The project would not specify that only the quietest available be used.	3(87)
88	KM	3.13-16	3.13.2	2	3		"2,770" should be "2,780"	3(88)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
89	MDT	3.14-9	3.14.3	3	2		The survey covered the entire area of the project upto the EFSEC boundary and the Natural gas pipeline ROW to the north. The area through the pipeline ROW (approximately 50ft) up to Grandview was not included in the survey. As with all areas of the project, if archeological remains are found, contruction activities in this area would stop until the appropriate authorities are notified.	3(89)
90	MDT	3.14-11	3.14.6	6			The completed archeological survey included detention pond 2, the interconnecting pipeway and access road #3. The substation inside the Refinery would be located on an existing gravel pad. The exact locations for the underground lines have not been determined, but the potential to find archeological resources in these areas are low. As with other all areas of the project, if archeological resources were found during excavation activities, then the appropriate authorities would be notified.	3(90)
91	DHE	3.15-9	Table 3.15-4			footnote 2	"Rate - Accidents per million vehicle miles." is erroneous, and should be corrected to "Rate - Accidents per million vehicles entering intersection."	3(91)
92	DHE	3.15-11	3.15.2	1	1		"(Access Road 1)" is in error, and should be corrected to "(Access Road 2)".	3(92)
93	DHE	3.15-11	3.15.2	1	2		Delete the second sentence, it is confusing. The primary construction access to the project is the Blaine road entrance. All other entrances would be internal.	3(93)
94	DHE	3.15-12	3.15.2	Table 3.15-6	last rows	last column	Please note. Because all the trip estimates in the application are based on 35, the actual traffic impacts are somewhat lower than the numbers in the application. These trip generation estimates for Project Operation Conditions are for 35 employees, which was BP's estimate at the time of the original traffic study two years ago. The DEIS now says 30 employees, but the trip generation has not been updated. The Total Trips for 30 employees would be 120 average weekday, 22 AM peak hour and 23 PM peak hour (Trips Entering and Exiting would change in proportion). However, since the numbers of trips generated during operation are so low, these differences in trips are not significant, and do not affect the impacts or mitigation.	3(94)
95	DHE	3.15-13	3.15.2	3	3		"(see Figure 3.1-6)" is erroneous, and should be corrected to "(see Figure 3.15-6)".	3(95)
96	KM	3.15-16	3.15.2	3	5		The sentence correctly states our earlier thoughts about barge transportation, in that it was anticipated that barge deliveries would not occur. Our current thinking is that barge deliveries are possible. Please leave this option open.	3(96)
97	DHE	3.15-17	Figure 3.15-7				At the end of the figure title, add "FOR PEAK CONSTRUCTION CONDITIONS"	3(97)
98	DHE	3.15-23	3.15.5			9	Delete "and Blaine Road/Grandview Road (SR 548)". See above comment for page 1-36, bullet number 3.	3(98)
99	MDT	3.16-1		2	5&6		Delete the last two sentences and add, "A Health and Safety Plan and Emergency and Security Plan would developed for the Cogeneration Project. These plans would coordinate with the Refinery's plans.	3(99)
100	MDT	3.16-17	3.16.2	3	2		Additional modeling would be performed for the Risk Management Plan and is not required at this time. This plan would require the facility to identify the 200 ppm endpoint. The 1000 ppm endpoint is not required.	3(100)

Expected Emissions after taking into account the effect of molecular weight

Expected Annual Emissions (tons/yr)	NOx	CO	VOC	PM_{10}	SO2	Totals
Primary Emissions						
Total from Cogeneration	181	81	28	94	50	434
Refinery Emission Reductions	(499)	(54)	(3)	(10)	(7)	(573)
Net Emissions	(318)	27	25	84	43	(139)
NOx (as NO2) to NH4NO3 Ratio	1.74					
SO2 to (NH4)2SO4 Ratio	2.06					
Secondary PM Formation Upon Aging	33%				20%	
Secondary PM Formed from NOx, SO2	104	-	-	-	21	
Secondary PM Avoided by Refinery Reductions	(286)				(3)	
Resulting Secondary Emissions						
Cogen Emissions After Secondary PM Formation	121	81	28	219	40	489
Emission Reductions After Secondary PM Formation	(334)	(54)	(3)	(299)	(6)	(696)
Net Emissions	(213)	27	25	(81)	34	(207)

NH4NO3 mol wt =	80	NH4NO3/NO2 =	1.74
(NH4)2SO4 mol wt =	132	(NH4)2SO4/SO2 =	2.06
NO2 mol wt =	46		
SO2 mol wt =	64		

Expected Emissions after taking into account the effect of molecular weight

Expected Annual Emissions (tons/yr)	NOx	CO	VOC	PM_{10}	SO2	Totals
Primary Emissions						
Total from Cogeneration	181	81	28	94	50	434
Refinery Emission Reductions	(499)	(54)	(3)	(10)	(7)	(573)
Net Emissions	(318)	27	25	84	43	(139)
NOx (as NO2) to NH4NO3 Ratio	1.74					
SO2 to (NH4)2SO4 Ratio	2.06					
Secondary PM Formation Upon Aging	33%				20%	
Secondary PM Formed from NOx, SO2	104	-	-	-	21	
Secondary PM Avoided by Refinery Reductions	(286)				(3)	
Resulting Secondary Emissions						
Cogen Emissions After Secondary PM Formation	121	81	28	219	40	489
Emission Reductions After Secondary PM Formation	(334)	(54)	(3)	(299)	(6)	(696)
Net Emissions	(213)	27	25	(81)	34	(207)

NH4NO3 mol wt =	80	NH4NO3/NO2 =	1.74
(NH4)2SO4 mol wt =	132	(NH4)2SO4/SO2 =	2.06
NO2 mol wt =	46		
SO2 mol wt =	64		